2004 INITIAL TRANSMISSION PROPOSAL
DIRECT TESTIMONY

BPA Exhibit No.	Subject	Witnesses
TR-04-E-BPA-03	**Overview of Rate Proposal**	**Metcalf, Gilman, Parker and Anasis**
TR-04-E-BPA-04	**Revenue Forecast**	**Woerner and Metcalf**
TR-04-E-BPA-05	**Revenue Requirement Study and Risk Analysis**	**Homenick, Jensen, Federovitch and Westman**

January 2003

TESTIMONY OF

DENNIS E. METCALF, DAVID L. GILMAN, NANCY PARKER

and

JOHN G. ANASIS

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: OVERVIEW OF RATE PROPOSAL

TESTIMONY OF

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SECTION 1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your names and qualifications.

A. My name is Dennis E. Metcalf and my qualifications are stated at TR-04-Q-BPA-06.

A. My name is David L. Gilman and my qualifications are stated at TR-04-Q-BPA-03.

A. My name is Nancy Parker and my qualifications are stated at TR-04-Q-BPA-07.

A. My name is John G. Anasis and my qualifications are stated at TR-04-Q-BPA-01.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide an overview of the 2004 Initial Rate Proposal, which is based on the Settlement Agreement for the 2004 Transmission Rate Case. This testimony also sponsors the 2004 Transmission and Ancillary Service Rate Schedules, TR-04-E-BPA-02.

Q. How is your testimony organized?

A. This testimony is organized in 4 sections. Section 1 is this Introduction. Section 2 provides an overview of the Settlement Agreement and discusses the proposed rates, with emphasis on the Ancillary and Control Area Services rates and Unauthorized Increase Charge. Section 3 addresses redispatch, and Section 4 addresses the equitable allocation standard in relation to the rate proposal.

SECTION 2. SETTLEMENT AGREEMENT AND INITIAL RATE PROPOSAL

Q. Please describe how the Transmission Business Line (TBL) and interested parties developed the Settlement Agreement for the 2004 Transmission Rate Case.

A. In order to establish transmission and ancillary service rates to be effective October 1, 2003, when current transmission and ancillary service rates expire, the TBL held a public workshop in August 2002 to begin discussing with interested parties issues associated with the upcoming 2004 Transmission Rate Case. At the parties' suggestion, TBL and the parties met often over the next two months to negotiate settlement of the rate case. The resulting Settlement Agreement includes transmission and ancillary service rate levels for the Fiscal Years 2004 and 2005 rate period, and addresses a small set of other issues. The Settlement Agreement was sent to TBL customers and interested parties for signature. TBL signed the Settlement Agreement after receiving signed agreements from most TBL customers. TBL's initial rate proposal reflects the terms of the Settlement Agreement. The Settlement Agreement is shown in Attachment 1. Attachment 2 is a list of the entities who have signed the Settlement Agreement.

Q. Please provide an overview of the TBL's Transmission and Ancillary Services Initial Rate Proposal.

A. TBL proposes to increase most Transmission and Ancillary Services rates by 1.5%, and to increase the Network Integration (NT) rate by 2.6%. The additional increase in the NT rate is intended to recover $1 million of redispatch costs. The Initial Proposal also includes a revised rate structure for the Energy Imbalance and Generation Imbalance rates, and a reduced Unauthorized Increase Charge.

Q. What is the basis of the 1.5% rate increase?

A. BPA held a public process, Programs in Review, in which the TBL developed its cost estimates for the Fiscal Years 2004-05 rate period. See TR-04-E-BPA-01, Chapter 2.

Based on these costs and the TBL's projections of load, a 1.5% increase will recover the TBL's costs for the rate period.

Q. Please describe the rate increase for FPT-04.3.

A. The FPT-04.3 rate is for FPT (Formula Power Transmission) contracts that, under the terms of the contracts, cannot be adjusted more frequently than once every three years. Since the rate was last adjusted on October 1, 2001, it cannot be adjusted again until October 1, 2004. We propose to increase the rate 3% at that time. A 3% rate increase for the second year of the rate period will recover the same revenues as a 1.5% increase applied to both years. The FPT-04.3 rate schedule also gives the customers the option to have a 1.5% increase starting October 1, 2003, which would result in the same overall rate increase during the rate period. If the customer elects a 1.5% increase commencing October 1, 2003, its FPT rate will be subject to adjustment on October 1, 2006.

Q. Why is the proposed NT rate increase greater than the proposed increase in all other rates?

A. The NT rate includes a Base Charge and a Load Shaping Charge. Under the TBL's proposal, the Base Charge is increased 1.5% and the Load Shaping Charge by $0.015/kilowatt (kW) per month. This increase is designed to recover $1 million above the amount that would be recovered by a 1.5% increase. This $1 million is intended to recover some of the costs of redispatch as specified in the Settlement Agreement (see Section 3, Redispatch). We estimate that the average increase in the NT rate is 2.6%. See TR-04-E-BPA-05, Attachment 4.

Q. *Why is the additional $1 million added to the Load Shaping Charge?*

A. As noted above, the NT rate consists of the Base Charge and the Load Shaping Charge. Under current rates, the NT Base Charge equals the PTP rate. By adding $1 million to the Load Shaping Charge, we were able to keep the Base Charge at the same level as the PTP rate.

Q. *Why is it important that the NT Base Charge equal the PTP rate?*

A NT customers may declare Customer Served Load, which is load served without use of NT service, including load internal to the customer's system, load served over nonfederal transmission, and load served through other transmission contracts with BPA. In some cases Customer Served Load is served through PTP contracts with BPA; for example, when the contract holder is the power supplier. Customer Served Load normally reduces the monthly billing factor for the Base Charge. By maintaining the Base Charge at the same level as the PTP rate, the PTP revenues the TBL collects when a PTP contract is used for Customer Served Load are the same as the lost NT revenues. This prevents arbitrage and gaming between the two services. *See* WP-96-E-BPA-85, pp. 17-19.

SECTION 2.a. ANCILLARY AND CONTROL AREA SERVICES RATES

Q. *How do the proposed Ancillary and Control Area Services differ from TBL's currently offered services?*

A. In addition to the 1.5% rate increase to the Ancillary Services and Control Area Service (ACS) rates discussed above, TBL proposes to revise other aspects of its ACS rates, which are modeled after the six ancillary services found in FERC Order 888.

Q. *What changes does TBL propose to the Scheduling, System Control and Dispatch Service and the Reactive Supply and Voltage Control from Generation Sources Service rates?*

A. TBL proposes to revise the Scheduling, System Control and Dispatch Service and the Reactive Supply and Voltage Control from Generation Sources Service rates, both of which are Ancillary Services, to clarify that the Billing Factor for each rate is based on all PTP transmission service purchased under TBL's Open Access Transmission Tariff, regardless of whether the Transmission Customer actually uses (schedules) the transmission. This is how TBL applies this rate now, and this change is intended solely to clarify the language of the rate schedule.

Q. *What changes does TBL propose for the Energy Imbalance (EI) Service, an Ancillary Service, and Generation Imbalance (GI) Service, a Control Area Service?*

A. TBL proposes to revise the rates for EI Service and GI Service to establish three Deviation Bands for each rate and to eliminate the 100 mills per kilowatthour (kWh) penalty charge, except for Intentional Deviations. Deviation Band 1 applies to small deviations (within 1.5% of the scheduled amount or 2 MW, whichever is larger); Deviation Band 2 to somewhat larger deviations (the portion of the deviation that exceeds the larger of 1.5% or 2 MW, but is less than the larger of 7.5% or 10 MW); and Deviation Band 3 applies to the largest deviations (those outside Band 2). In addition, wind resources and new generation resources undergoing testing before commercial operation will be exempt from Deviation Band 3 for GI Service.

Q. *Please discuss the rationale for the proposed rate design.*

A. The graduated rate design provides incentives for customers to schedule accurately, but does not penalize customers that employ good scheduling practices. Deviations in Band 1 are charged or credited BPA's incremental cost. Deviations within Band 2 are charged or credited BPA's incremental cost, plus or minus 10%. This pricing encourages good scheduling practices but does not unduly penalize customers for such deviations. However, Band 3 deviations, which are deviations greater than 7.5%, or 10 MW, of the scheduled amount of energy should not occur if the customer employs good scheduling practices. Deviations of this magnitude should have a significant penalty. TBL is proposing to charge/credit Band 3 deviations at BPA's incremental cost plus/minus 25%.

Q. *Why is TBL proposing to eliminate the 100 mills/kWh penalty charge?*

A. TBL's current 2002 EI and GI rate schedules charge a minimum of 100 mills/kWh for a positive deviation outside the deviation band. When energy prices are low, this charge may be several times the incremental cost and is too severe a penalty. However, under the proposed rates, the proposed Band 3 rate increases in relation to the price of energy, and, for positive deviations, is always 25 percent above the incremental cost. The 100 mills/kwh charge was retained in the proposed imbalance rates for Intentional Deviation, because the penalty should be severe for this action.

Q. Are any resources exempt from the Deviation Band 3 rate?

A. Yes. Wind resources and new resources undergoing testing before commercial operation are exempted from Band 3 (BPA Incremental Cost plus 25%) under the proposal. Wind resources do not yet have the technology to predict output with sufficient accuracy to consistently avoid the penalty rate, while it is not generally possible to schedule accurately while testing new resources. Therefore, the penalty would not be a true deterrent to inaccurate scheduling in these cases.

Q. What changes does TBL propose for Operating Reserve - Spinning Reserve Service and Operating Reserve - Supplemental Reserve Service rates?

A. TBL proposes to revise its Operating Reserve rates to require the generators in the BPA Control Area to pay for or return energy provided by BPA in the event of a contingency at that generator. Further, TBL clarifies that it can direct customers or generators, as applicable, to either purchase operating reserve energy at the applicable market index price, or return the energy to BPA at specified times.

Currently, under the ACS-02 rate schedule, transmission customers are responsible for the cost of energy supplied in a contingency. In a given hour several customers may be purchasing power from a given generator and scheduling power under their transmission contracts. Under current rates, the cost of contingency energy is assigned to all transmission customers scheduling power from the generator at the time of the contingency. This assignment of cost has proved to be difficult to track. In addition, the parties to the involved power sales contracts often have had to adjust the contracts to avoid having the power purchaser pay twice for the same energy. During the contingency, the power is delivered to the customer by the control area. Therefore, the customer continues to pay the generator for the power. If TBL charges the customer for the contingency energy, the customer needs to seek a settlement with the generator.

Finally, the generator can take actions to minimize the number and duration of contingencies, so assigning the cost obligation for contingency energy to the generator that experiences the contingency is more consistent with cost causation principle

Q. Please describe the revision of the Spill Condition definition found in the General Rate Schedule Provisions.

A. TBL proposes to revise the definition of Spill Condition to specify that a Spill Condition, for the purpose of determining a credit or payment for deviations under the Energy Imbalance or Generation Imbalance rates, exists only when spill physically occurs on the BPA system. This was the intent of the existing language, and this change is a clarification.

SECTION 2.b. UNAUTHORIZED INCREASE CHARGE

Q. Please describe the proposed Unauthorized Increase Charge (UIC).

A. The proposed UIC is two times the rate applicable to the customer's transmission service. This is a reduction from the current 2002 UIC of four times the monthly PTP rate for Long-Term Service. For NT customers, the proposed UIC rate is $2.056/kW, two times the NT Base Charge. For PTP Transmission Service customers, the UIC rate is two times the rate applicable to the customer's service, capped at two times the monthly charge for Long-Term Service. The proposed UIC rate is more in line with typical UIC rates charged in the utility industry. No changes are proposed for the Billing Factors and the UIC Relief sections of the UIC.

Q. Please give examples of how the UIC rate would be determined.

A. <u>Example 1</u>. A PTP customer with a long-term reservation on the Southern Intertie will pay $2.352/kW (2 x $1.176/kW) on the highest one-hour Unauthorized Increase (UI) in the month.

Example 2. A PTP customer with a short-term reservation for 50 days on the Network will pay a capped UIC rate of $2.056/kW (2 x $1.028/kW) on the highest one-hour UI. The PTP rate that applies to this reservation is $1.81/kW (($.047/kW/day x 5 days) + ($.035/kW/day x 45 days)). Two times this rate is $3.62/kW, but the UIC rate is capped at two times the Long-Term monthly PTP rate, or $2.056/kW. Thus, the applicable UIC rate is $2.056/kW because it is lower than two times the rate for the transmission service.

Example 3. A PTP customer with a short-term reservation for 10 hours on the Network will pay a UIC rate of $.059/kW on the highest one-hour UI. The proposed PTP Hourly rate is 2.96 mills/kWh. The applicable UIC rate is two times the Hourly Transmission rate applied to the number of hours of the transmission reservation (2.96 mills/kWh x 10 hours x 2).

SECTION 3. REDISPATCH

Q. Please explain the settlement provisions concerning redispatch.

A. TBL agrees to submit to FERC a revised Attachment K to the OATT defining the redispatch services to be provided by PBL. TBL agrees to pay PBL $3 million per year for redispatch services. A fixed annual payment was agreed to because of the difficulties of calculating the actual costs of redispatch. During the rate period, we will work toward developing a methodology for determining the costs of redispatch and compensating parties that provide redispatch. Any information developed on the amount of redispatch provided by PBL will be provided to any party requesting it.

Q. How is the $3 million per year recovered?

A. As noted above, $1 million per year is added to the NT Load Shaping Charge. The remaining $2 million per year is recovered in the overall 1.5% increase to all transmission rates. This allocation of the redispatch costs was negotiated as part of the Settlement.

SECTION 4. EQUITABLE ALLOCATION

Q. Do the proposed transmission and ancillary services rates represent an equitable allocation of costs between Federal and non-Federal power?

A. Yes. TBL is not presenting segmentation and cost allocation studies to support the proposed rates, the rates are a product of the Settlement Agreement. Nevertheless, equitable allocation is demonstrated in two important ways. First, equitable allocation between Federal and non-Federal power is achieved through adherence to the principle of comparability. Prior to 1996, when most transmission for Federal power was provided for in bundled power sales contracts, an allocation of costs in the rate case was needed to demonstrate equitable allocation of transmission costs between Federal and non-Federal power. Under BPA's Open Access Transmission Tariff, purchasers of transmission for Federal power, including both BPA's Power Business Line (PBL) and PBL's customers, receive the same service and pay the same rates as purchasers of transmission for non-Federal power. BPA draws no distinction between Federal and non-Federal power using the system. An equitable allocation of transmission costs between Federal and non-Federal power is achieved through application of the same rates to the two classes of service. A separate rate case allocation is unnecessary. Second, equitable allocation is demonstrated by the breadth of the settlement and the diversity among the settling parties. The settling parties include the PBL and PBL full requirements customers; large partial requirements customers that both buy Federal power and wheel large amounts of non-Federal power; large wheeling customers, such as the region's Investor Owned Utilities, which purchase little Federal power; and power marketers and resource developers. The TBL would not have been able to obtain the agreement of such a large group of customers with such diverse interests unless the proposed allocation of costs was equitable.

Q. *Does this conclude your testimony?*

A. Yes.

SETTLEMENT AGREEMENT
Bonneville Power Administration 2004 Transmission Rate Case

The undersigned signatories to this Settlement Agreement hereby agree to the following:

1. In the Bonneville Power Administration (BPA) 2004 Transmission Rate Case (Rate Case), the Transmission Business Line (TBL) will submit a proposal (Initial Proposal) commencing the rate process for the period FYs 2004 – 2005 (Rate Period) that reflects the following:

   a. Current 2002 transmission rates will be increased by 1.5%, and the 2002 transmission rate schedules and the general rate schedule provisions will otherwise be unchanged except as explicitly set forth below. If a rate schedule includes a maximum charge for any rate, the increase in rate level will be applied to the maximum charge. The following transmission rates will be increased by 1.5%: FPT-02.1; IR-02; NT-02 (Base Charge and Load Shaping Charge); PTP-02; IS-02; IM-02; and Delivery Charge (Utility Delivery). The FPT-02.3 charges will remain in effect for FY 2004, and will be increased by 3% for FY 2005. The increase in the FPT-02.3 rate shall be considered an adjustment to such rate. Therefore, such rate will next be subject to adjustment on October 1, 2007.

      In addition, the General Transfer Agreement Delivery Charge will increase 1.5%.

   b. In addition to the above increase, the NT Load Shaping Charge will be increased by an additional $0.015/kW per month to recover approximately $1 million of the total amount paid by the TBL to the BPA Power Business Line (PBL) for redispatch associated with NT service. The NT rate schedule will otherwise be unchanged.

   c. The ACS rate schedule and General Rate Schedule Provision Spill Condition definition will be as specified in Attachment 1 to this Settlement Agreement.

   d. The Unauthorized Increase Charge (UIC) rate under all rate schedules that apply to Point-to-Point Transmission Service (the PTP, IS, and IM rate schedules) will equal two times the transmission rate (which, for short-term service, is based on the length of the reservation), but shall not in any month exceed 2 times the monthly rate for Long-Term Firm Transmission Service under such rate schedule. The UIC under the NT rate schedule will equal two times the NT Base Charge. Examples of the calculation of the UIC charge are shown in Attachment 2.

   The Initial Proposal transmission and ancillary service rates are shown in Attachment 3.

2. Redispatch

   a. The signatories recognize and agree that there is value associated with the redispatch of hydro resources. The signatories further agree that during the FY 2004-2005 Rate Period they will work towards devising an approach so that hydro-electric and other generation can be appropriately compensated for redispatch in future rate periods. If TBL develops information during the Rate Period regarding the amount of redispatch by PBL, TBL will provide such information to any party requesting it.

b. The revised Open Access Transmission Tariff (OATT) Attachment K (shown in Attachment 4 to this Settlement Agreement) will replace the existing Attachment K. The TBL will compensate the PBL for redispatch services associated with Attachment K by paying PBL $3 million per year in FY 2004 and FY 2005 for all such services provided during such period. In the interest of reaching a settlement the signatories have agreed to this amount of compensation to the BPA PBL for providing redispatch during the Rate Period. However, nothing in this Settlement Agreement nor actions taken pursuant to section 2.a, above, will serve as a precedent for any methodology for implementing or valuing redispatch for future rate periods, or for the purpose of determining the rights of an RTO or any other regional transmission provider to require redispatch.

c. TBL will submit the revised Attachment K (Attachment 4 to this Settlement Agreement) to the Federal Energy Regulatory Commission (FERC) as a proposed amendment to BPA's Open Access Transmission Tariff, and will request that it be effective as of October 1, 2003. The signatories agree not to challenge the approval of the revised Attachment K by FERC, and, if FERC approves the revised Attachment K without change, the signatories agree not to challenge such approval in any judicial forum.

3. The TBL will convene a Business Practices and Systems Forum as set forth in Attachment 5 to this Settlement Agreement.

4. No later than October 1, 2003, TBL will have appropriate scheduling and reservation systems in place so that customers are able to redirect firm transmission service by modifying points of receipt and delivery and are able to return to their original points upon expiration of the redirected service, in accord with FERC policy. To the extent permitted by FERC policy, customers will be permitted to redirect firm transmission irrespective of other requests for firm transmission if and to the extent that the redirected firm transmission service would make the same use of the same constrained paths as the original transmission service to the original points of receipt and delivery. TBL will make all reasonable efforts to have such systems available for testing by March 1, 2003.

5. The signatories agree not to contest any aspect of the TBL's Initial Proposal, including but not limited to the level of any transmission or ancillary or control area services rate or any of the elements thereof, the methodologies and principles used to derive such rates, or any aspect of the rate schedules, and agree to waive their rights to cross-examination and discovery with respect thereto. If, however, the TBL does not submit an Initial Proposal consistent with the terms of this Settlement Agreement, the signatories may contest any aspect of the TBL's proposal.

6. If no party in the Rate Case contests any aspect of the TBL Initial Proposal, the TBL will propose to the Administrator that he adopt the TBL's Initial Proposal and establish rates consistent therewith.

7. The signatories will move the Hearing Officer to specify a date within a reasonable time of the prehearing conference by which any party to the Rate Case that has not executed this Settlement Agreement i) must object to the settlement proposed in this Settlement Agreement and identify each issue such party chooses to preserve for hearing; or ii) be deemed to have waived any right to object to the settlement proposal or preserve issues for hearing. If no party objects to the settlement proposal and preserves issues for hearing, the TBL shall propose to the Administrator that he adopt the Initial Proposal in its entirety. In the event that any party does so object, the TBL may, but shall not be required to, revise the

Initial Proposal as it believes appropriate, either after such party states its objection or after parties file their direct testimony. If the TBL decides not to revise its Initial Proposal, the TBL will propose to the Administrator that he adopt the Initial Proposal in its entirety. If the TBL decides to revise its Initial Proposal, the TBL and the parties will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing the TBL a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to such revised proposal. The signatories may contest any aspect of such revised proposal.

8. If the TBL submits an Initial Proposal consistent with the terms of this Settlement Agreement, and does not submit a revised proposal pursuant to section 7, the signatories agree not to enter any evidence into the Rate Case or make any argument in the Rate Case contesting any provision of section 36 of BPA's current OATT. If the Administrator establishes transmission rates consistent with the TBL's Initial Proposal and submits such rates to FERC for confirmation and approval, the signatories agree not to make any such argument before the FERC or any judicial forum during the Rate Period.

9. Nothing in this Settlement Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's transmission rates or the signatories' rights to challenge such revisions.

10. If the Administrator establishes transmission rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval only under the applicable standards of the Northwest Power Act and as part of a reciprocity filing, the signatories agree not to challenge such confirmation and approval of such rates or any element thereof, including the methodologies and principles used to establish such rates, or support or join any such challenge, and agree not to challenge such rates or any element thereof, including the methodologies and principles used to establish such rates, in any judicial forum. In addition, the TBL's commitment in section 4 of this Settlement Agreement shall apply only if the Administrator establishes rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval.

11. The signatories agree that they will not assert in any forum that anything in this Settlement Agreement or any action with regard to this Settlement Agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.

12. By executing this Settlement Agreement, no signatory waives any right to pursue BPA OATT dispute resolution procedures consistent with BPA's OATT (including without limitation any complaint concerning implementation of BPA's OATT) or any claim that a particular charge, methodology, practice or rate schedule has been improperly applied

13. Nothing in this Settlement Agreement amends any contract or modifies rights or obligations or limits the remedies available thereunder.

This Settlement Agreement may be executed in counterparts.

__________________________for

____________________________ Date ______

Party

Attachment 1

SCHEDULE ACS-04
ANCILLARY SERVICES AND
CONTROL AREA SERVICES RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule ACS-02. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k). Service under this schedule is subject to BPA-TBL's General Rate Schedule Provisions (GRSPs).

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Provider is required to offer to provide (a) Operating Reserve – Spinning, and (b) Operating Reserve – Supplemental to the Transmission Customer serving load with generation located in the Transmission Provider's Control Area. The Transmission Customer serving load with generation located in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Service rates available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve -- Spinning Reserve Service
6. Operating Reserve -- Supplemental Reserve Service

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations, but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) criteria.

Control Area Service rates available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve -- Spinning Reserve Service
4. Operating Reserve -- Supplemental Reserve Service

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

The rates below apply to Transmission Customers taking Scheduling, System Control and Dispatch Service from BPA-TBL. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Scheduling, System Control and Dispatch Service.

1. RATES

a. Long-Term Firm PTP Transmission Service and NT Service

The rate shall not exceed $0.166 per kilowatt per month.

b. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(a) Days 1 through 5 $0.008 per kilowatt per day

(b) Day 6 and beyond $0.005 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.48 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a, 1.b(1), and for Hourly Firm PTP Transmission Service specified in 1.b(2) shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in section 1.b(2) for Hourly Non-Firm Service shall be the scheduled kilowatthours.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A of the Network Integration Rate Schedule (NT-02).

SECTION II. ANCILLARY SERVICE RATES

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources Service from BPA-TBL. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. RATES

a. Long-Term Firm PTP Transmission Service and NT Service

The rate shall not exceed $0.067 per kilowatt per month.

b. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Nonfirm Service

(a) Days 1 through 5 $0.003 per kilowatt per day

(b) Day 6 and beyond $0.002 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.19 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a, 1.b(1) and for Hourly Firm PTP Transmission Service specified in 1.b(2) shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in section 1.b(2) for Hourly Non-Firm Service shall be the scheduled kilowatthours.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A of the Network Integration Rate Schedule (NT-02).

c. Adjustment for Self-Supply

The Billing Factors in sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA-TBL's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

SECTION II. ANCILLARY SERVICE RATES

C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.30 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

SECTION II. ANCILLARY SERVICE RATES

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA-TBL. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a schedule hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TBL will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each hour) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA-TBL will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(i) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(ii) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation i) greater than ± 1.5% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

(i) When energy taken by the Transmission Customer in a schedule hour is greater than the energy scheduled, the charge is 110% of BPA's incremental cost.

(ii) When energy taken by the Transmission Customer in a schedule hour is less than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(i) When energy taken by the Transmission Customer in a schedule hour is greater than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during the that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(ii) When energy taken by the Transmission Customer in a schedule hour is less than the scheduled amount, the credit is 75% of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the PNW. If no adequate hourly index exists, an alternative index will be used. The index to be used will be posted on the OASIS at least 30 days prior to use for determining the BPA incremental cost and will not be changed more often than once per year unless BPA-TBL determines that the existing index is no longer a reliable price index.

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any hour of that day.

c. Intentional Deviation

For any hour(s) that an imbalance is determined by BPA-TBL to be an Intentional Deviation:

(1) No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of: i) 125% of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour.

SECTION II. ANCILLARY SERVICE RATES

E. OPERATING RESERVE -- SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve -- Spinning Reserve Service from BPA-TBL and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. For a Transmission Customer's load (located inside or outside of the BPA Control Area) served by generation located in the BPA Control Area, the Transmission Customer's Spinning Reserve Requirement shall be determined consistent with applicable NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of the Transmission Customer's Spinning Reserve Requirement.

b. For energy delivered, the generator shall, as directed by BPA-TBL, either:

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

2. BILLING FACTORS

a. The Billing Factor for Spinning Reserve Service is determined in accordance with applicable WECC and NWPP standards. Application of current standards establish a minimum Spinning Reserve Requirement equal to the sum of:

(i) Two and a half percent (2.5%) of the hydroelectric generation dedicated to the Transmission Customer's firm load responsibility; and

(ii) Three and a half percent (3.5%) of non-hydroelectric generation dedicated to the Transmission Customer's firm load responsibility.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION II. ANCILLARY SERVICE RATES

F. OPERATING RESERVE -- SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve -- Supplemental Reserve Service from BPA-TBL and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. For a Transmission Customer's load (located inside or outside the BPA Control Area) served by generation located in the BPA Control Area, the Transmission Customer's Supplemental Reserve Requirement shall be determined consistent with applicable NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of Supplemental Reserve Requirement.

b. For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA-TBL, either :

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports (see section 2.a(iii)). The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. BILLING FACTORS

a. The Billing Factor for Supplemental Reserve Service is determined in accordance with applicable WECC and NWPP standards. Application of current standards establish a minimum Supplemental Reserve Requirement equal to the sum of:

(i) Two and one half percent (2.5%) of the hydroelectric generation dedicated to the Transmission Customer's firm load responsibility, plus

(ii) Three and one half percent (3.5%) of non-hydroelectric generation dedicated to the Transmission Customer's firm load responsibility, plus

(iii) Any power scheduled into the BPA Control Area that can be interrupted on ten (10) minutes' notice.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA-TBL transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.30 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TBL will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each hour) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA-TBL will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(i) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(ii) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation i) greater than ± 1.5% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

(i) When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 110% of BPA's incremental cost.

(ii) When energy delivered from the generation resource is greater than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(i) When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(ii) When energy delivered from the generation resource is greater than the scheduled amount, the credit is 75% of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the PNW. If no adequate hourly index exists, an alternative index will be used. The index to be used will be posted on the OASIS at least 30 days prior to use for determining the BPA incremental cost and will not be changed more often than once per year unless BPA-TBL determines that the existing index is no longer a reliable price index.

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than schedules) for any hour of that day.

c. Intentional Deviation

No credit is given for negative deviations (actual generation greater than schedules) for any hour(s) that the imbalance is an Intentional Deviation (as determined by BPA-TBL).

For positive deviations (actual generation less than schedules) which are determined by BPA-TBL to be Intentional Deviations, the charge is the greater of: i) 125% of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour.

d. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

i) wind resources; and

ii) new generation resources undergoing testing before commercial operation for up to 90 days.

All such deviations greater than ± 1.5% or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

SECTION III. CONTROL AREA SERVICE RATES

C. OPERATING RESERVE -- SPINNING RESERVE SERVICE

Operating Reserve -- Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA-TBL, and such Spinning Reserve Service is not provided for under a BPA-TBL transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of Spinning Reserve Requirement

b. For energy delivered, the customer shall, as directed by BPA-TBL, either:

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

2. BILLING FACTORS

a. The Billing Factor for Spinning Reserve Service is determined in accordance with applicable WECC and NWPP standards. Application of current standards establish a minimum Spinning Reserve Requirement equal to the sum of:

(i) Two and one half percent (2.5%) of the hydroelectric generation dedicated to the customer’s firm load responsibility, plus

(ii) Three and one half percent (3.5%) of non-hydroelectric generation dedicated to the customer’s firm load responsibility.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

D. OPERATING RESERVE -- SUPPLEMENTAL RESERVE SERVICE

Operating Reserve -- Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA-TBL, and such Supplemental Reserve Service is not provided for under a BPA-TBL transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of Supplemental Reserve Requirement

b. For energy delivered, the customer shall, as directed by BPA-TBL, either:

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

2. BILLING FACTORS

a. The Billing Factor for Supplemental Reserve Service is determined in accordance with applicable WECC and NWPP guidelines. Application of current guidelines establish a minimum Supplemental Reserve Requirement equal to the sum of:

(i) Two and one half percent (2.5%) of the hydroelectric generation dedicated to the customer's firm load Responsibility, plus

(ii) Three and one half percent (3.5%) of non-hydroelectric generation dedicated to the customer's firm load responsibility, plus

(iii) Any power scheduled into the BPA Control Area that can be interrupted on ten (10) minutes' notice.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA §212 specified in section II.D of the GRSPs.

GRSP – Section III Definitions

61. Spill Condition

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

Attachment 2
Unauthorized Increase Charge (UIC) Examples

1. Reservation

The customer purchases 10 MWs of PTP for 9 days, January 29 to February 6.

Unauthorized Increase (UI)

On January 30, the customer schedules 15 MWs under this reservation, a UI of 5 MWs. This is the highest UI for this Reservation for the month of January.

PTP rate for 9-day service (Short-Term Weekly Service)

(5 days*.047) + (4 days*.035) = $0.375 per kW

PTP rate for Long-Term service

$1.028 per kW per month

Since the 9-day rate for short-term weekly service is less than the monthly rate for long-term service, the 9-day rate is used.

UIC rate

2 * .375 = $0.75 per kW

UIC charge for January

5,000 kW * $0.75 per kW = $3,750

2. Reservation

The customer purchases 10 MWs of IS for 40 days, January 20 to February 28.

Unauthorized Increase (UI)

On January 30, the customer schedules 15 MWs under this reservation, a UI of 5 MWs. This is the highest UI for this Reservation for the month of January.

IS rate for 40-day service (Short-Term Monthly Service)

(5 days * .054) + (35 days * .040) = $1.670 per kW

IS rate for Long-Term Service

$1.176 per kW per month

Since the 40-day rate for short-term monthly service is greater than the monthly rate for long-term service, the monthly rate for long-term service is used to calculate the UIC.

UIC rate

2 * 1.176 = $2.352 per kW

UIC charge for January

5,000 kW * $2.352 per kW = $11,760

Attachment 3
Initial Proposal Rates

RATE	**$/kW/mo** (except where noted)
FPT-04.1	
Main Grid	
• Distance	$0.0511/mile
• Interconnection Terminal	0.53
• Terminal	0.59
• Miscellaneous Facilities	2.91
Secondary System	
• Distance	$0.5021/mile
• Transformation	5.49
• Intermediate Terminal	2.12
• Interconnection Terminal	1.50
FPT-04.3 (FY 2005) *	
Main Grid	
• Distance	$0.0518/mile
• Interconnection Terminal	0.54
• Terminal	0.60
• Miscellaneous Facilities	2.96
Secondary System	
• Distance	$0.5095/mile
• Transformation	5.57
• Intermediate Terminal	2.15
• Interconnection Terminal	1.52
* FPT-04.3 rates will remain at FPT-02.3 levels for FY 2004, and increase by 3% (shown here) over FPT-02.3 levels for FY 2005.	
IR-04	1.261
NT-04	
• Base	1.028
• Load Shaping	0.425 * *(reflects 1.5% + $1M)
PTP-04	
• Long-Term	1.028
• Short-Term (per day)	
• Days 1-5	.047
• Day 6 and beyond	.035
• Hourly	2.96 mills/kWh

Attachment 3
Initial Proposal Rates (cont'd)

RATE	$/kW/mo (except where noted)

IS-04
• Long-Term
• Short-Term (per day)
  • Days 1-5
  • Day 6 and beyond
• Hourly
	
	1.176
	
	.054
	.040
	3.39 mills/kWh

IM-04
• Long-Term
• Short-Term (per day)
  • Days 1-5
  • Day 6 and beyond
• Hourly
	
	1.258
	
	.058
	.042
	3.61 mills/kWh

Utility Delivery Charge	.946
GTA Delivery Charge	.946
Unauthorized Increase Charge	• <u>PTP Service</u>: Not to exceed 2 times the monthly rate for Long-Term Service • <u>NT Service</u>: $2.056/kW/mo

ACS-04
Scheduling
• Long-Term
• Short-Term (per day)
  • Days 1-5
  • Day 6 and beyond
• Hourly
 	
Generation Reactive
• Long-Term
• Short-Term (per day)
  • Days 1-5
  • Day 6 and beyond
• Hourly
 	
Regulation and Frequency Response (Ancillary & Control Area rates)
 	
Operating Reserves (Ancillary & Control Area rates)
	
	.166
	
	.008
	.005
	0.48 mills/kWh
	
	.067
	
	.003
	.002
	0.19 mills/kWh
	
	.30 mills/kWh
	
	8.39 mills/kWh

Attachment 4

Open Access Transmission Tariff
Revised Attachment K

For the period October 1, 2003, through September 30, 2005, to the extent the Transmission Provider determines that redispatch of Network Resources is necessary to maintain Network Integration Transmission (NT) Service, the Transmission Provider shall implement redispatch in accordance with the provisions of this Attachment K. Attachment K addresses only circumstances in which the Tariff requires NT and Point-to-Point (PTP) uses on a constraint be reduced on a comparable basis.

1. The Transmission Provider shall not issue redispatch instructions under this Attachment K to increase ATC.

2. The BPA Power Business Line (PBL) will inform the Transmission Provider of all non-power constraints that limit the PBL's ability to redispatch generation resources. The Transmission Provider will not violate these non-power constraints unless an emergency situation leaves no other alternative for maintaining system reliability or providing safety to individuals or property. Notwithstanding any other provision of Attachment K, the protection of transmission system reliability and the safety of people and property will be the primary criteria the Transmission Provider will use in an emergency situation.

3. PBL will provide the Transmission Provider federal hydroelectric generation resource set points. The Transmission Provider may request changes to such set points. Not all changes to set points are redispatch.

4. For redispatch that occurs within the hour of delivery:

   If the Transmission Provider determines that a redispatch of federal hydro-electric projects is necessary to maintain the reliability of the FCRTS in real-time and the Transmission Provider is unable to calculate the portion of the constraint attributable to NT schedules, the Transmission Provider may redispatch the federal hydro-electric projects as necessary to relieve the constraint for the remainder of the hour and, if the event occurs twenty minutes past the hour, for the next hour also. However, the Transmission Provider must make the determination described in section 5 as soon as possible, not to exceed 100 minutes after the need for redispatch arises, and adjust the redispatch instructions accordingly.

5. For Day-ahead and Hour-ahead redispatch:

    a. The Transmission Provider will use redispatch only to manage congestion on the FCRTS that would impact NT schedules. The Transmission Provider will redispatch the system only to the extent necessary to maintain the NT schedules.

    b. The Transmission Provider will not issue any redispatch instructions until it has curtailed all non-firm schedules across the constrained path.

    c. If the Transmission Provider determines that a constraint can be relieved by redispatching federal hydro-electric projects, the Transmission Provider will determine what portion of the constraint is caused by NT schedules and what portion is caused by PTP schedules. Then the Transmission Provider will issue a redispatch instruction in an amount that will relieve the NT portion of the constraint and will curtail the PTP schedules in an amount necessary to relieve the PTP portion of the constraint.

    d. If the Transmission Provider determines that the portion of the constraint caused by NT schedules cannot be relieved by only redispatching federal hydro-electric projects, the Transmission Provider will contact the PBL schedulers and inform the PBL schedulers of the amount of NT schedule associated with the constraint. The PBL schedulers will attempt to relieve the constraint by the least cost means, including, but not limited to, purchasing alternative transmission from a third party, purchasing replacement generation from a third-party and redispatching federal generation accordingly, or requesting third party generation to decrease and using federal generation to replace the third-party generation. In making these arrangements the PBL will act as a purchasing agent for the Transmission Provider.

6. The Transmission Provider will not request redispatch for any purpose under the Tariff other than that stated herein or otherwise required by the Tariff.

Attachment 5

Business Practices and Systems Forum

BPA TBL will meet with Transmission Customers at least three times between November 2002 and September 2003 to discuss Business Practices and systems used to implement TBL's Open Access Transmission Tariff and its Transmission and Ancillary Service Rate Schedules. TBL agrees to discuss the following issues identified during TBL Rate Case Workshops held in September and October 2002:

1. TBL's Business Practices on Operating Reserves – Spinning and Supplemental Services,
2. Real Power Losses,
3. Curtailment during Real-Time, including PTP curtailment based on contract demand vs. schedules, and
4. Scheduling practices and associated systems, including wind resource scheduling.

Prior to the first meeting, TBL will draft and circulate principles to govern the meetings. TBL will post on its website the meeting location and agenda at least 10 days prior to each meeting. The first meeting will take place no later than December 13, 2002.

TBL and the Transmission Customers agree to use best efforts to ensure that the appropriate technical, and other, staff attend the meetings (either in person or by telephone conference) to facilitate meaningful discussions.

The parties agree that these meetings are designed to supplement, not revise, TBL's existing process to develop its Business Practices and systems. Further, while TBL agrees to work in good faith to discuss and address Transmission Customer concerns, TBL retains discretion to determine whether to make any changes to its Business Practices or systems as a result of the meetings. TBL will use the meetings to solicit feedback for use in developing or revising its Business Practices or systems, but is under no obligation to develop new Business Practices or systems or make any changes to existing Business Practices or systems. If TBL changes its Business Practices or systems, whether on its own or as a result of Transmission Customer input at the meetings, it will use its best efforts to implement those changes in a timely manner pursuant to TBL's established Business Practice process. The Transmission Customers retain all rights under TBL's Open Access Transmission Tariff, as it may be amended, to challenge TBL's Business Practices.

Attachment 2

ENTITIES THAT HAVE SIGNED
THE 2004 TRANSMISSION RATE CASE SETTLEMENT AGREEMENT
AS OF JANUARY 8, 2003

Alcoa, Inc.
Avista Corp.
Avista Energy, Inc.
Bonneville Power Administration Power Business Line
Clallam County Public Utility District
Clark Public Utilities
Columbia Falls Aluminum Company, LLC
Town of Eatonville
City of Ellensburg
Emerald People's Utility District
Fairchild Air Force Base 92nd Contracting Squadron
Golden Northwest Aluminum, Inc.
Idaho Energy Authority
  Signing for:
  City of Burley
  City of Declo
  East End Mutual Electric Co., Ltd.
  Farmer's Electric Company
  City of Heyburn
  Idaho County Light & Power Cooperative, Inc.
  Idaho Falls Power
  Lower Valley Energy, Inc.
  City of Minidoka
  Riverside Electric Co., Ltd
  City of Rupert
  City of Soda Springs
  South Side Electric, Inc.
  United Electric Cooperative, Inc.
Idaho Power, Inc.
Industrial Customers of Northwest Utilities
Kittitas Public Utility District
City of Klamath Falls
Lakeview Light & Power
Lewis County Public Utility District
Mason Public Utility District No. 1
Mason County Public Utility District No. 3
City of Milton

Northwest Requirement Utilities
Signing for:
City of Ashland
Benton REA
Big Bend Electric Cooperative
Canby Utility
City of Cascade Locks
Central Lincoln Public Utility District
Columbia Basin Electric Cooperative
Columbia Power Cooperative
Columbia REA
Columbia River Public Utility District
East End Mutual Electric Company
Ferry County Public Utility District #1
Flathead Electric Cooperative
City of Forest Grove
Harney Electric Cooperative
Hood River Electric Cooperative
City of Idaho Falls
Inland Power & Light
Klickitat County Public Utility District
McMinnville Water & Light
Midstate Electric Cooperative
Modern Electric Water Company
City of Monmouth
Nespelem Valley Cooperative
Northern Wasco County Public Utility District
Orcas Power & Light Cooperative
Oregon Trail Electric Cooperative
City of Richland
City of Rupert
Salem Electric
Skamania County Public Utility District
Surprise Valley Electrification Corp.
Tanner Electric Cooperative
Tillamook People's Public Utility District
United Electric Cooperative
Vera Water & Power
Wasco Electric Cooperative
Wells Rural Electric
Western Montana Electric G&T Cooperative
Northwestern Energy
Northwestern Wind Power, LLC
OHOP Mutual Light Company
PacifiCorp, Inc.

PacifiCorp Power Marketing, Inc.
Pacific County Public Utility District No. 2
Pacific Northwest Generating Cooperative
Signing for:
Blachly-Lane Electric Cooperative
Clearwater Power Company
Consumers Power Inc.
Fall River Rural Electric Cooperative
Okanogan County Electric Cooperative
Umatilla Electric Cooperative
West Oregon Electric Cooperative
Central Electric Cooperative
Coos-Curry Electric Cooperative
Douglas Electric Cooperative
Lane Electric Cooperative
Northern Lights, Inc.
Salmon River
Raft River Rural Electric Cooperative
Parkland Light & Water Company
Peninsula Light Company
City of Port Angeles
Portland General Electric
Power Resource Managers, LLP
Signing for:
Benton Public Utility District
Franklin Public Utility District
Grays Harbor Public Utility District
Powerex Corp.
Public Generating Pool
Signing for:
Cowlitz County Public Utility District No. 1
Douglas County Public Utility District No. 1
Grant County Public Utility District No. 2
Pend Oreille County Public Utility District No. 1
City of Seattle, City Light Department
Public Power Council
Puget Sound Energy, Inc.
Renewable Northwest Project
Snohomish County Public Utility District
Town of Steilacoom
Tacoma Public Utilities
Wahkiakum Public Utility District

TESTIMONY OF

JOHN R. WOERNER AND DENNIS E. METCALF

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE FORECAST

TESTIMONY OF

JOHN R. WOERNER AND DENNIS E. METCALF

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE FORECAST

SECTION 1. INTRODUCTION AND PURPOSE

Q. Please state your name and qualifications.

A. My name is John R. Woerner. My qualifications are stated in TR-04-Q-BPA-09.

A. My name is Dennis E. Metcalf. My qualifications are stated in TR-04-Q-BPA-06.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor and describe Bonneville Power Administration (BPA) Transmission Business Line's (TBL) revenue forecast for Fiscal Years (FY) 2003-2005.

Q. How is your testimony organized?

A. This testimony is organized in three sections. Section 1 is this Introduction. Section 2 describes the derivation of the sales forecast and presents summaries of long-term and short-term sales. Section 3 briefly describes the revenue forecast and presents a summary of the FY 2003-2005 revenue forecast.

SECTION 2. SALES FORECAST

Q. How are transmission sales forecast?

A. For most NT and Utility Delivery customers, Network Integration (NT) rate and Utility Delivery charge sales are calculated using point of delivery (POD) load forecasts. These POD forecasts are straight-line extrapolations from at least five years of history combined with local knowledge about individual points. For large generating customers, NT sales are developed from the PNUCC White Book load forecast. Formula Power Transmission (FPT) sales are based on existing contracts. Point-to-Point (PTP), Integration of Resources (IR), and Southern Intertie (IS) sales are forecast using a statistical model. Summaries of the long-term and short-term sales forecasts by rate are shown on Attachments 1 and 2, respectively.

Q. Please describe the statistical approach used to forecast sales under PTP, IR, and IS rates.

A. Sales were forecast using a regression analysis that used daily observations of total sales from three and one-half years of history from January 1999 through June 2002. Four analyses of transmission sales were performed based on the transmission segment and direction of the transmission purchase: (1) the Southern Intertie, north to south; (2) the Network headed to the Southern Intertie; (3) the Southern Intertie, south to north; and (4) the Network headed to the PNW or Canada. Variables capturing historical trend, the economy, electric loads, hydro storage, intertie capacity, and bulk-hub power prices were used in each of the four analyses.

Q. Does the model distinguish between long-term and short-term sales?

A. No. The model forecasts total sales for each day. The total sales are then separated into long-term and short-term as described below.

Q. How are long-term PTP and IR sales on the Network segment determined?

A. Long-term sales on the Network segment are based on the demands in existing long-term contracts. In order to forecast the extent of rollover of existing contracts upon their expiration, long-term sales on the Network segment were divided into two groups—those that served load of the transmission contract holder and those remaining, which are presumably associated with bulk power marketing. To the extent load-serving contracts expire, they are assumed to be replaced at their current levels, plus 1.3% to account for load growth. To the extent the bulk power marketing contracts expire, they are assumed to be replaced at 75% of their previous level because rollover of such contracts is much more speculative.

Q. How are short-term PTP Network sales calculated?

A. A preliminary estimate of short-term PTP sales is based on the forecast of total PTP and IR sales from the forecasting model, minus long-term sales. This preliminary forecast based on the model results is then compared to the actual FY 2002 short-term sales. If the model results are less than the actual FY 2002 short term sales, the model results are used. If the model results are greater than the actual FY 2002 sales, then the model results are averaged with the actual FY 2002 sales to determine the final short-term PTP sales forecast.

Q. How are long-term and short-term Southern Intertie sales determined?

A. Long-term Southern Intertie sales were kept at their FY 2002 levels—that is, all long-term contracts are assumed to be rolled over at their existing demand levels. A preliminary estimate of short-term IS sales is based on the forecast of total IS sales from the forecasting model, minus long-term sales. This preliminary forecast based on the model results are then adjusted based on FY 2002 actual short-term sales using the same method described above for PTP short-term sales.

Q. Please describe the effect of the planned Pacific DC Intertie (PDCI) Modernization Project on the sales forecast.

A. The TBL and the Intertie owners on the southern end of the PDCI are working to modernize infrastructure at each respective end. In this rate case sales forecast, reductions to capacity on the PDCI due to the modernization project are modeled as lost transmission sales for power sales headed to southern California. The reductions in transmission capacity were estimated monthly beginning in January 2003 and ran for selected months through April 2005. For the sales forecast, only short-term sales are affected by the reductions in PDCI capacity.

SECTION 3. REVENUE FORECAST

Q. Please describe the revenue forecast.

A. A summary of the revenue forecast by product by year is shown on Attachment 4. The revenue forecast is shown assuming current rates and proposed rates. Attachment 3 shows current 2002 rates and proposed 2004 rates. The revenues from PTP, IR, NT, IS and Utility Delivery sales are calculated by applying the rates to the forecasted sales discussed above.

Q. How were revenues for Ancillary and Control Area Services estimated?

A. The billing factors for the two required Ancillary Services, Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service, are the same as the billing factors for transmission service. Thus, the sales forecasts generated for the Network and Southern Intertie transmission sales were also used for the revenue forecast of the two required Ancillary Services.

Operating Reserves Services were assumed to remain at FY 2002 levels because no new control area generation is forecast during the rate period. Regulation and Frequency Response Service was assumed to grow at 0.75% per year. No net revenues were assumed from Energy and Generation Imbalance Services.

Q. Are all sources of revenue affected by the proposed rate increase?

A. No. Certain monies come into the business line from sources other than the general transmission rates. These are referred to here as revenue credits because in rate setting they are used to credit costs prior to calculating the general rates. They include revenue from certain rates such as the Townsend Garrison Transmission (TGT) and Southern Intertie Annual Costs (AC) rates, as well as revenue from various services that TBL provides such as O&M.

Q. *How are these revenues forecast?*

A. Revenue credits are forecast at FY 2002 levels with adjustments for known changes. These revenues, accounting for less that 10% of TBL revenues, are shown on Attachment 4 tables, lines 31-43.

Q. *Does this conclude your testimony?*

A. Yes.

Attachment 1
Transmission Sales, Long-term Contracts
(Megawatts)

	Transmission Rate Schedule	MWs 1/	(A) Oct	(B) Nov	(C) Dec	(D) Jan	(F) Feb	(G) Mar	(H) Apr	(I) May	(J) Jun	(K) Jul	(L) Aug	(M) Sep	(N) Annual
	Network														
	FY 2004														
1	Formula Power Transmission (FPT.1).............	a_cd	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	2,540	**2,540**
2	Formula Power Transmission (FPT.3).............	a_cd	716	716	716	716	716	716	716	716	716	716	716	716	**716**
3	Integration of Resources (IR)...................	a_cd	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,379	**4,585**
4	Point to Point (PTP)...........................	a_cd	15,236	15,749	15,441	15,789	15,789	15,789	15,614	15,699	15,691	15,691	16,070	16,070	**15,719**
5	Network Integration (Base Charge)	cp	4,814	5,310	6,197	6,324	6,389	5,544	4,793	4,290	3,927	4,312	4,427	3,950	**5,023**
6	**Subtotal Network**		**27,910**	**28,918**	**29,498**	**29,973**	**30,038**	**29,193**	**28,267**	**27,848**	**27,477**	**27,863**	**28,357**	**27,655**	**28,583**
	FY 2005														
7	Formula Power Transmission (FPT.1).............	a_cd	2,540	2,540	2,540	2,257	2,257	2,257	2,257	2,257	2,257	2,257	2,257	2,257	**2,328**
8	Formula Power Transmission (FPT.3).............	a_cd	716	716	716	716	716	716	716	716	716	716	716	716	**716**
9	Integration of Resources (IR)...................	a_cd	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,604	4,379	**4,585**
10	Point to Point (PTP)...........................	a_cd	16,299	16,212	15,900	16,361	16,361	16,361	16,383	16,468	16,315	16,315	16,372	16,372	**16,310**
11	Network Integration (Base Charge)	cp	4,897	5,396	6,293	6,461	6,565	5,675	4,915	4,409	4,040	4,431	4,565	4,074	**5,143**
12	**Subtotal Network**		**29,056**	**29,467**	**30,053**	**30,399**	**30,503**	**29,613**	**28,875**	**28,453**	**27,932**	**28,323**	**28,513**	**27,797**	**29,082**
13	Network Integration (Load Shaping), FY 2004......	cp	5,446	5,894	6,721	7,001	7,077	6,264	5,596	5,018	4,647	4,960	4,984	4,673	**5,690**
14	Network Integration (Load Shaping), FY 2005......	cp	5,528	5,979	6,817	7,094	7,209	6,350	5,673	5,093	4,717	5,035	5,094	4,764	**5,780**
	PSW Intertie														
	FY 2004														
15	Intertie South (IS) (Assured Delivery)...........	m_cd	400	400	367	367	367	367	367	367	367	367	367	400	**375**
16	Point to Point (PTP) Service.....................	a_cd	5,441	5,353	5,353	5,393	5,143	4,573	4,968	5,661	5,789	5,703	5,703	4,810	**5,324**
17	**Subtotal Intertie**............................	**a_cd**	**5,841**	**5,753**	**5,720**	**5,760**	**5,510**	**4,940**	**5,335**	**6,028**	**6,156**	**6,070**	**6,070**	**5,210**	**5,699**
	FY 2005														
18	Intertie South (IS) (Assured Delivery)...........	m_cd	400	400	367	367	367	367	367	367	367	367	367	367	**373**
19	Point to Point (PTP) Service.....................	a_cd	5,441	5,353	5,353	5,393	5,143	4,573	4,968	5,661	5,789	5,703	5,703	4,843	**5,327**
20	**Subtotal Intertie**............................	**a_cd**	**5,841**	**5,753**	**5,720**	**5,760**	**5,510**	**4,940**	**5,335**	**6,028**	**6,156**	**6,070**	**6,070**	**5,210**	**5,699**
	Utility Delivery														
21	Delivery Sales, FY 2004.........................	cp	226	228	276	286	300	254	238	212	194	217	213	187	**236**
22	Delivery Sales, FY 2005.........................	cp	230	233	281	292	306	259	242	216	198	221	217	191	**241**

1/ Annual (a_cd) or monthly (m_cd) contract demand; "cp" coincidental peak denotes contribution to TBL transmission system peak load.

Attachment 2
Transmission Sales, Short-term Contracts
(Megawatts)

	Short-term Product	Units (MW)	(A) Oct.	(B) Nov.	(C) Dec.	(D) Jan.	(F) Feb.	(G) Mar.	(H) Apr.	(I) May	(J) Jun.	(K) Jul.	(L) Aug.	(M) Sep.	(N) Annual
	Network														
	FY 2004														
1	PTP Block1 (day 1 thru 5).....	MW	16	30	11	1	4	11	606	393	1,116	721	386	423.35	**310**
2	PTP Block2 (day 6 and beyond).	MW	479	377	538	450	484	676	565	570	1,186	1,164	622	683	**649**
3	PTP Hourly..................	aMW	194	239	431	1,085	974	714	1,583	1,552	828	1,707	913	1,001	**935**
4	**Subtotal Network ....**		**689**	**645**	**981**	**1,535**	**1,461**	**1,400**	**2,753**	**2,514**	**3,130**	**3,591**	**1,921**	**2,107**	**1,894**
	FY 2005														
5	PTP Block1 (day 1 thru 5).....	MW	17	39	13	1	5	15	720	489	1,352	853	550	575	**386**
6	PTP Block2 (day 6 and beyond).	MW	490	499	592	620	693	908	671	709	1,436	1,376	887	928	**817**
7	PTP Hourly..................	aMW	198	316	474	1,494	1,396	960	1,882	1,930	1,003	2,019	1,301	1,361	**1,194**
8	**Subtotal Network ....**		**704**	**854**	**1,079**	**2,115**	**2,094**	**1,883**	**3,273**	**3,128**	**3,791**	**4,248**	**2,737**	**2,865**	**2,398**
	Southern Intertie														
	FY 2004														
9	IS Block1 (day 1 thru 5)......	MW	0	0	0	7	122	154	78	0	0	0	0	88	**37**
10	IS Block2 (day 6 and beyond)..	MW	0	360	710	564	719	1,315	547	0	0	0	0	637	**404**
11	IS Hourly...................	aMW	0	37	59	260	225	44	30	0	0	0	0	57	**59**
12	**Subtotal Intertie..........**		**0**	**397**	**768**	**831**	**1,066**	**1,513**	**656**	**0**	**0**	**0**	**0**	**782**	**501**
	FY 2005														
13	IS Block1 (day 1 thru 5)......	MW	0	0	0	12	183	186	153	43	295	92	92	201	**105**
14	IS Block2 (day 6 and beyond)..	MW	0	94	157	895	1,080	1,585	1,072	705	493	669	667	1,460	**740**
15	IS Hourly...................	aMW	0	10	13	412	339	53	60	50	51	60	60	131	**103**
16	**Subtotal Intertie..........**		**0**	**104**	**170**	**1,319**	**1,602**	**1,824**	**1,285**	**799**	**839**	**821**	**819**	**1,792**	**948**

Attachment 3
Summary of Rate Level Changes

		Units	(A) Current 2002 Rates	(B) Proposed 2004 Rates	(C)
	FPT.1 and FPT.3 Formula Power Transmission			**FPT.1**	**FPT.3 */**
1	M-G Distance..........................	$/kW-mi-yr)	0.0503	0.0511	0.0518
2	M-G Miscellaneous Facilities...........	($/kW-yr)	2.87	2.91	2.96
3	M-G Terminal..........................	($/kW-yr)	0.58	0.59	0.60
4	M-G Interconnection Terminal...........	($/kW-yr)	0.52	0.53	0.54
5	S-S Transformation.....................	($/kW-yr)	5.41	5.49	5.57
6	S-S Interconnection Terminal...........	($/kW-yr)	1.48	1.50	1.52
7	S-S Intermediate Terminal..............	($/kW-yr)	2.09	2.12	2.15
8	S-S Distance..........................	$/kW-mi-yr)	0.4947	0.5021	0.5095
9	Overall FPT Rate......................	($/kW-mo)	0.942	0.956	0.761
	IR Integration of Resources				
10	Demand................................	($/kW-mo)	1.243	1.261	
	NT Network Integration				
11	Base Rate ($/kW-mo)....................	($/kW-mo)	1.013	1.028	
12	Load Shaping ($/kW-mo).................	($/kW-mo)	0.404	0.425	
13	Base plus Load Shaping.................	($/kW-mo)	1.417	1.453	
	PTP Point-to-Point				
14	Demand................................	($/kW-mo)	1.013	1.028	
15	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	0.046	0.047	
16	Daily Block 2 (day 6 and beyond)........	($/kW-day)	0.034	0.035	
17	Hourly................................	(mills/kWh)	2.92	2.96	
	Unauthorized Increase Charge				
18	Cap Rate for PTP; NT CSL Peak Underrun..	($/kW-mo)	6.078	2.056	
	Utility Delivery				
19	Demand................................	($/kW-mo)	0.932	0.946	
	IS Southern Intertie				
20	Demand................................	($/kW-mo)	1.159	1.176	
21	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	0.053	0.054	
22	Daily Block 2 (day 6 and beyond)........	($/kW-day)	0.039	0.040	
23	Hourly................................	(mills/kWh)	3.34	3.39	
	IM Montana Intertie				
24	Demand................................	($/kW-mo)	1.239	1.258	
25	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	0.057	0.058	
26	Daily Block 2 (day 6 and beyond)........	($/kW-day)	0.041	0.042	
27	Hourly................................	(mills/kWh)	3.56	3.61	
	IE Eastern Intertie				
28	IE....................................	(mills/kWh)	1.32	1.32	

Attachment 3
Summary of Rate Level Changes

		Units	(A) Current 2002 Rates	(B) Proposed 2004 Rates	(C)
	Power Factor Penalty Charge				
29	Demand -- Lagging......................	($/kVAr-mo)	0.28	0.28	
30	Demand -- Leading......................	($/kVAr-mo)	0.24	0.24	
31	Energy -- Lagging or Leading...........	$/kVAr-hour)	n.a.	n.a.	
	ACS Scheduling, System Control and Dispatch				
32	Demand.................................	($/kW-mo)	0.164	0.166	
33	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	0.008	0.008	
34	Daily Block 2 (day 6 and beyond)........	($/kW-day)	0.005	0.005	
35	Hourly.................................	(mills/kWh)	0.47	0.48	
	ACS Reactive Supply and Voltage Control from Generation Sources				
36	Demand.................................	($/kW-mo)	0.066	0.067	
37	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	0.003	0.003	
38	Daily Block 2 (day 6 and beyond)........	($/kW-day)	0.002	0.002	
39	Hourly.................................	(mills/kWh)	0.19	0.19	
	ACS Regulation and Frequency Response				
40	Hourly.................................	(mills/kWh)	0.30	0.30	
	ACS Energy Imbalance				
41	Hourly.................................	(mills/kWh)	100.00	n.a.	
	ACS Operating Reserves				
42	Spinning...............................	(mills/kWh)	8.27	8.39	
43	Supplemental...........................	(mills/kWh)	8.27	8.39	

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*/ FPT.3 not increased until FY 2005, then it is increased 3%.

Attachment 4
TBL Revenues under Current Rates

			(A) RateLevel	(B) RateUnits	(C) FY2003 ($000)	(D) FY2004 ($000)	(E) FY2005 ($000)
	Long-Term						
	Network						
1	FPT.1	Formula Power Transmission........................	0.942	($/kW-mo.)	28,710	28,710	26,311
2	FPT.3	Formula Power Transmission........................	0.739	($/kW-mo.)	6,347	6,347	6,347
3	IR	Integration of Resources..........................	1.243	($/kW-mo.)	68,393	68,393	68,393
4	PTP	Point to Point....................................	1.013	($/kW-mo.)	182,210	191,082	198,263
5	NT	Network Integration Transmission, Base Charge.....	1.013	($/kW-mo.)	60,072	61,061	62,524
6	NT	Network Integration Transmission, Load Shaping....	0.404	($/kW-mo.)	27,235	27,586	28,019
	PSW Intertie						
7	IS	Intertie South Assured Delivery...................	1.159	($/kW-mo.)	5,219	5,219	5,181
8	IS	Intertie South....................................	1.159	($/kW-mo.)	74,049	74,049	74,087
	Short-Term						
	Network						
9	PTP	Monthly,Weekly,Daily Block 1......................	0.046	($/kW-day)	5,176	5,201	6,476
10	PTP	Monthly,Weekly,Daily Block 2......................	0.034	($/kW-day)	7,831	8,085	10,148
11	PTP	Hourly..	2.92	($/MWh)	23,630	23,981	30,525
	PSW Intertie						
12	IS	Monthly,Weekly,Daily Block 1......................	0.053	($/kW-day)	1,752	717	2,002
13	IS	Monthly,Weekly,Daily Block 2......................	0.039	($/kW-day)	10,743	5,749	10,484
14	IS	Hourly..	3.34	($/MWh)	2,968	1,724	2,975
	Delivery						
15	NT/PTP	Utility...	0.932	($/kW-mo.)	2,805	2,636	2,687
16	UFT	Industry..		($/kW-mo.)	3,337	3,428	3,493
	Ancillary and Control Area Services (ACS)						
	Scheduling Control & Dispatch						
17		Annual..	0.164	($/kW-mo.)	50,441	52,037	53,437
18		Monthly,Weekly,Daily Block 1......................	0.008	($/kW-day)	1,165	1,013	1,429
19		Monthly,Weekly,Daily Block 2......................	0.005	($/kW-day)	2,529	1,926	2,837
20		Hourly..	0.47	($/MWh)	4,221	4,102	5,332
	Generation Supplied Reactive						
21		Annual..	0.066	($/kW-mo.)	20,299	20,942	21,505
22		Monthly,Weekly,Daily Block 1......................	0.003	($/kW-day)	437	380	536
23		Monthly,Weekly,Daily Block 2......................	0.002	($/kW-day)	1,012	770	1,135
24		Hourly..	0.19	($/MWh)	1,706	1,658	2,155
	Operating Reserves						
25		Spinning..	8.27	($/MWh)	20,885	20,885	20,885
26		Supplemental......................................	8.27	($/MWh)	20,885	20,885	20,885
27		Contingency.......................................			0	0	0
28	**Regulation and Frequency Response**............................		0.30	($/MWh)	11,524	12,079	12,634
29	**Generation Imbalance**...				0	0	0
30	**Energy Load Imbalance**..				0	0	0
	Revenue Credits						
31	AC/NFPDEPR	AC rate and NFP Depreciation......................			5,689	5,780	5,780
32	CSPE/SUPCAP	Columbia Storage Pwr Exchange.....................			156	0	0
33	DIRCBUR	Direct Corp and Bureau............................			1,854	1,854	1,854
34	FIBER	Fiber...			12,752	12,765	2,781
35	GI	Generation Integration Costs......................			7,235	7,235	7,235
36	O&M	Operation and Maintenance Srvcs...................			1,008	1,035	1,084
37	PCW	Wireless Personal Communications..................			3,277	3,444	3,620
38	PFP	Power Factor Penalty..............................			2,332	2,332	2,332
39	RAS	PSW Remedial Action Scheme........................			139	139	139
40	RSRV CHRG	Long-Term Reservation Fees........................			1,136	1,295	1,302
41	TGT	Townsend Garrison Transmission....................			9,840	9,840	9,840
42	UDU	Utility Delivery Underrecovery....................			2,000	0	0
43	UFT	Use of Facilities (utility).......................			7,158	7,353	7,493
44		**Subtotal Network**..............................			**409,605**	**420,446**	**437,007**
45		**Subtotal Intertie**.............................			**94,730**	**87,457**	**94,729**
46		**Subtotal Delivery**.............................			**6,142**	**6,064**	**6,180**
47		**Subtotal Ancillary**............................			**135,104**	**136,678**	**142,769**
48		**Subtotal Revenue Credits**......................			**54,576**	**53,072**	**43,460**
49		**Total TBL**			**700,156**	**703,717**	**724,145**

Attachment 4
TBL Revenues under Proposed Rates

			(A) RateLevel	(B) RateUnits	(C) FY2004 ($000)	(D) FY2005 ($000)
	Long-Term					
	Network					
1	FPT.1	Formula Power Transmission........................	0.956	($/kW-mo.)	29,137	26,702
2	FPT.3	Formula Power Transmission........................	0.761	($/kW-mo.)	6,347	6,536
3	IR	Integration of Resources..........................	1.261	($/kW-mo.)	69,383	69,383
4	PTP	Point to Point....................................	1.028	($/kW-mo.)	193,912	201,199
5	NT	Network Integration Transmission, Base Charge.....	1.028	($/kW-mo.)	61,965	63,450
6	NT	Network Integration Transmission, Load Shaping....	0.425	($/kW-mo.)	29,020	29,476
	PSW Intertie					
7	IS	Intertie South Assured Delivery...................	1.176	($/kW-mo.)	5,296	5,257
8	IS	Intertie South....................................	1.176	($/kW-mo.)	75,135	75,173
	Short-Term					
	Network					
9	PTP	Monthly,Weekly,Daily Block 1......................	0.047	($/kW-day)	5,314	6,617
10	PTP	Monthly,Weekly,Daily Block 2......................	0.035	($/kW-day)	8,323	10,447
11	PTP	Hourly..	2.96	($/MWh)	24,309	30,943
	PSW Intertie					
12	IS	Monthly,Weekly,Daily Block 1	0.054	($/kW-day)	730	2,040
13	IS	Monthly,Weekly,Daily Block 2......................	0.040	($/kW-day)	5,897	10,753
14	IS	Hourly..	3.39	($/MWh)	1,750	3,020
	Delivery					
15	NT/PTP	Utility...	0.946	($/kW-mo.)	2,676	2,728
16	UFT	Industry..		($/kW-mo.)	3,428	3,493
	Ancillary					
	Scheduling Control & Dispatch					
17		Annual..	0.166	($/kW-mo.)	52,672	54,088
18		Monthly,Weekly,Daily Block 1......................	0.008	($/kW-day)	1,013	1,429
19		Monthly,Weekly,Daily Block 2......................	0.005	($/kW-day)	1,926	2,837
20		Hourly	0.48	($/MWh)	4,190	5,445
	Generation Supplied Reactive					
21		Annual..	0.067	($/kW-mo.)	21,259	21,831
22		Monthly,Weekly,Daily Block 1......................	0.003	($/kW-day)	380	536
23		Monthly,Weekly,Daily Block 2......................	0.002	($/kW-day)	770	1,135
24		Hourly	0.19	($/MWh)	1,658	2,155
	Operating Reserves					
25		Spinning..	8.39	($/MWh)	21,188	21,188
26		Supplemental......................................	8.39	($/MWh)	21,188	21,188
27		Contingency.......................................			0	0
28	**Regulation and Frequency Response**	....	0.30	($/MWh)	12,079	12,634
29	**Generation Imbalance**	....			0	0
30	**Energy Load Imbalance**	....			0	0
	Revenue Credits					
31	AC/NFPDEPR	AC-xx/NFP Depreciation............................			5,780	5,780
32	CSPE/SUPCAP	Columbia Storage Pwr Exchange.....................			0	0
33	DIRCBUR	Direct Corp and Bureau............................			1,854	1,854
34	FIBER	Fiber...			12,765	2,781
35	GI	Generation Integration Costs......................			7,235	7,235
36	O&M	Operation and Maintenance Srvcs...................			1,035	1,084
37	PCW	Wireless Personal Communications..................			3,444	3,620
38	PFP	Power Factor Penalty..............................			2,332	2,332
39	RAS	PSW Remedial Action Scheme........................			139	139
40	RSRV CHRG	Long-Term Reservation Fees........................			1,295	1,302
41	TGT	Townsend Garrison Transmission....................			9,840	9,840
42	UDU	Utility Delivery Underrecovery....................			0	0
43	UFT	Use of Facilities (utility).......................			7,353	7,493
44		**Subtotal Network**................................			**427,710**	**444,752**
45		**Subtotal Intertie**...............................			**88,807**	**96,243**
46		**Subtotal Delivery**...............................			**6,104**	**6,221**
47		**Subtotal Ancillary**..............................			**138,324**	**144,466**
48		**Subtotal Revenue Credits**........................			**53,072**	**43,460**
49		**Total TBL**.......................................			**714,016**	**735,142**

TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, MICHAEL R. FEDEROVITCH

and

ERIK D.WESTMAN

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE REQUIREMENT STUDY AND RISK ANALYSIS

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SECTION 1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your names and qualifications.

A. My name is Ronald J. Homenick and my qualifications are contained in TR-04-Q-BPA-04.

A. My name is Dana M. Jensen and my qualifications are contained in TR-04-Q-BPA-05.

A. My name is Michael R. Federovitch and my qualifications are contained in TR-04-Q-BPA-02.

A. My name is Erik D. Westman and my qualifications are contained in TR-04-Q-BPA-09.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor the development of transmission revenue requirements for the Federal Columbia River Transmission System (FCRTS). This testimony also sponsors the Revenue Requirement Study, TR-04-E-BPA-01 and the Documentation for the Revenue Requirement Study, TR-04-E-BPA-01A.

Q. *How is your testimony organized?*

A. Our testimony addresses significant changes from Bonneville Power Administration's (BPA's) practices in prior rate cases in the assumptions and methods used to determine transmission revenue requirements and to demonstrate cost recovery. First, in Section 2, we address changes related to the transmission revenue requirement, including the treatment of Delivery facilities sales and the revenue financing of capital programs. In Section 3, we address risk analysis. In Section 4, we address technical changes to the transmission repayment study. In Section 5, we discuss potential adjustments and updates for the Final Rate Proposal.

SECTION 2. REVENUE REQUIREMENTS

Q. *What changes have been made in the way BPA determines transmission revenue requirements?*

A. There have been no changes in the methodology BPA uses for determining revenue requirements. However, the transmission revenue requirements for Fiscal Years (FYs) 2004 and 2005 incorporate $20 million per year for revenue financing of capital investments.

Q. *What is revenue financing?*

A. Revenue financing is an alternate financing mechanism to fund transmission capital investments. In calculating the revenue requirement, BPA assumes that cash generated annually by the transmission business operation is used to finance capital projects in lieu of issuing traditional debt instruments such as bonds. For the FY 2004-2005 rate period, the amount of new debt forecasted to be issued through bonds will be the annual capital expenditures less the proposed amount of revenue financing.

Q. *Why is BPA using revenue financing?*

A. The primary reason for utilizing revenue financing is to help BPA manage its borrowing authority constraints. As a government agency, BPA has a debt borrowing ceiling of $3.75 billion, established by the Federal Columbia River Transmission System Act of 1974, Pacific Northwest Electric Power Planning and Conservation Act of 1980, Continuing Appropriations for 1983 and Energy and Water Development Appropriation Act of 1984. Current projections of capital expenditures show that BPA would run out of borrowing authority around FY 2005 or FY 2006. Through revenue financing BPA preserves a portion of its finite borrowing authority by avoiding the issuance of additional debt. Revenue financing also improves BPA's financial profile because BPA is not relying entirely on debt financing. Rating agencies look more favorably on entities that use less than 100% debt financing. Therefore, a balanced approach that combines debt financing and revenue financing may result in higher financial ratings for BPA and lower interest rates on future BPA bonds issued.

Q. *Was revenue financing used in prior rate cases?*

A. Yes, in the 1983, 1995, and 1996 BPA rate filings.

Q *What was the dollar amount of revenue financing used in previous rate filings?*

A. Transmission revenue financing was $6.6 million in the 1983 rate filing, and $15 million per year for the 1995 and 1996 rate filings. As a percentage of projected capital investments for the applicable rate period, revenue financing was about 5%

Q. How was the current amount determined?

A. For the current rate case, the Transmission Business Lines (TBL) assumed that capital investments amortized using an average useful life of five years or less would be eligible for revenue financing. TBL's Information Technology (IT) capital investments generally carry a useful life of 5 years. Because IT investments usefulness erodes quickly as technology changes, they have the appropriate characteristics for revenue financing. Moreover, some companies, including utilities, do not debt finance a portion or all of their short-lived capital investments. IT capital investments for this rate period as a percentage of projected capital investments is about 5%. This percentage is consistent with past practices, as stated above.

Q. How is revenue financing incorporated into the determination of revenue requirements?

A. As in the aforementioned rate filings, revenue financing is included in the Statement of Cash Flows as a cash requirement that is not addressed directly in the expenses, like the repayment of Treasury bonds and Congressional appropriations. For each year, it is manifest as the difference between the increase in long-term debt, or the projected borrowing for the year, and the cash used for utility plant, or the projected capital expenditures for that year. Without revenue financing, these two elements would have equal values. To reflect the $20 million of revenue financing, the increase in long-term debt is $20 million less than the cash used for capital expenditures in that year. That difference affects the annual increase or decrease in cash, which factors into the determination of Minimum Required Net Revenues. *See* Revenue Requirement Study, TR-04-E-BPA-01, Chapter 4.1.2.

Q. Are there other areas in which changes have occurred that affect revenue requirements?

A. Yes. As in the last rate filing, the sale of Delivery segment facilities resulting from the 1996 Sale of Facilities Policy have had an effect on the revenue requirements, both from actual and forecasted sales. From FYs 1997 through 2002, sales proceeds totaled $41 million, with a book value for the facilities sold of $33.3 million. Proceeds from sales closed in FYs 1997 through 1999 were applied as additional amortization to transmission debt ($23.4 million) to reduce overall repayment obligations, consistent with the transfer of title of these assets. An additional $9.9 million remains to be applied as amortization. In order to provide the same effect in revenue requirements as if it had been used for amortization, that amount is included in the transmission cash reserves to provide interest income to offset interest expense on outstanding debt. As such, it is not available for risk mitigation.

Q. What is the treatment in revenue requirements for the forecasted sales of Delivery facilities in FY 2003?

A. TBL staff identified the facilities projected to be sold by the end of the current rate period. The gross investment in those facilities was removed from the plant-in-service in 2003. The total proceeds that TBL expects to receive for these sales is $6.3 million, based on the judgment of TBL staff involved with the sales. The book value of these facilities is estimated as $7.6 million. The forecasted proceeds, along with the actual proceeds, were included in the calculation of interest income on cash balances that is an offset to interest expense in the revenue requirement. The amount equivalent to the book value is unavailable for risk mitigation.

Q. Have you included any sales of facilities for the rate period in your analysis?

A. No. Although the sales policy will remain in effect during the rate period, we have not reflected any sales during the rate period in any of our analyses.

Q. Are there any other changes related to revenue requirements?

A. Yes. For the test of the adequacy of revenues from proposed rates to demonstrate full cost recovery by year in the rate period, it was necessary to move $3.5 million of planned amortization from FY 2004 to FY 2005. *See* Revenue Requirement Study, TR-04-E-BPA-01, Chapter 4.4. The proposed revenues were insufficient to cover all cash requirements in FY 2004, but were more than sufficient in FY 2005. Consequently, we reshaped the planned amortization to accommodate this pattern. In total in the rate period, there is the same amount of amortization in the revised revenue test as was revenue requirements. This reshaping has been a long-standing practice in previous rate filings in order to ensure adequate cash flows from proposed rates to meet annual cash requirements. It was not necessary to do this in the last transmission rate filing, however.

SECTION 3. RISK ANALYSIS

Q. Has TBL made any changes to its risk analysis methodology?

A. No. TBL used the same method and spreadsheet model for the risk analysis in the 2002 Final Transmission Proposal. *See* 2002 Final Revenue Requirement Study, TR-02-FS-BPA-01, Section 2.2; 2002 Final Revenue Requirement Documentation, TR-02-FS-BPA-01A, Chapter 9; Westman and Sapp, TR-02-E-BPA-07.

Q. What are the results of the risk analysis?

A. In this rate proposal, TBL has identified and quantified transmission risks and has designed risk mitigation tools that achieve BPA's policy standard of a 95 percent U.S. Treasury Payment Probability (TPP). Financial reserves attributed to the transmission function, expected to total $162 million at the beginning of FY 2004, and the ability to revise rate levels after FY 2005 achieve the TPP standard without the need to include any planned net revenue for risk in the revenue requirement. 2004 Initial Revenue Requirement Study, TR-04-E-BPA-01, Section 2.2.

SECTION 4. TECHNICAL CHANGES IN REPAYMENT STUDIES

Q Have there been any changes to the repayment model?

A. Yes. Since the 2002 Final Transmission Proposal in May 2000, BPA has implemented new repayment model software, the Ferrand Jordan Repayment Model. The old model was written in Fortran and it was becoming increasingly difficult to find people proficient in Fortran programming to modify and keep the program running. The old Fortran model was not developed to accommodate scenario analysis (analyzing outcomes based on differing assumptions), which has become a critical need at BPA. The new Ferrand Jordan model offers more flexibility within the optimization goal of solving for the lowest minimum revenue level that meets all repayment obligations with interest as well as an interface that uses all of the benefits of a Windows-based approach.

The new Ferrand Jordan model offers two basic modes of operation:

1) The first mode uses the ***same*** equations used in the FORTRAN repayment model, but uses simplex calculation method of linear programming rather than binary iteration to optimize. This changes the order in which bonds are scheduled to be paid to more thoroughly minimize the revenue needed to repay the debt service.

2) The second mode is a ***full replication*** of the original Fortran model and is the mode that BPA is using for regulatory repayment runs. It includes the portion of the program that determines which bonds to call based on highest coupon adjusted for the call premiums. *See* Revenue Requirement Study, TR-04-E-BPA-01, Appendix A; and Revenue Requirements Study Documentation, at TR-04-E-BPA-01A, Chapter 13 for further explanation of the Repayment Model.

Q. Which mode is BPA using to produce the amortization schedule in this rate case?

A. BPA uses the second mode in all regulatory runs. The first mode ignores the "priority of payments" required by law in the Federal Columbia River Transmission System Act, Oct. 18, 1974, 88 Stat. 1376, as amended, and by Department of Energy policy RA 6120.2 (the "priority of payments" language requires BPA to pay all other creditors before repaying its debt to the Treasury); therefore, it is used only for scenario analysis and debt planning. *See* Revenue Requirement Study, TR-04-E-BPA-01, Chapter 5.

Q. Does this new model introduce any changes from the old model?

A. Yes.

1) One minor change the Ferrand Jordan model introduces is to stop the practice of rounding all numbers to the nearest $1000. All numbers generated by the Ferrand Jordan model are un-rounded, which gives a greater degree of accuracy to the results.

2) A second change between the models is in the way the input data is formatted and manipulated. Instead of producing and maintaining separate database files (in the form of a text file) for each year (15 files for a 5-year run), the new model now keeps all obligations in only 3 databases—a historical federal, a projected federal, and a third party. This is a significant time saver which also reduces input errors while facilitating error tracking.

SECTION 5: ANTICIPATED CHANGES FOR THE FINAL RATE PROPOSAL

Q. What changes in the Revenue Requirement are anticipated for the Final Rate Proposal?

A. Since the Initial Proposal includes the capital and expense forecasts from the closeout of Programs In Review, there are no changes expected in those areas. The only expected changes for the Final Proposal will be to update fully for FY 2002 actual financial data. That will include plant investment (affecting depreciation expense and the calculation of repayment study replacements), borrowing (affecting interest expense), and any update of transmission financial reserves from actual FY 2002 and forecasted FY 2003 results. In the case of 2002 actual borrowing, as part of its capital strategy BPA issued bonds with terms considerably shorter than the service lives of the associated assets. Typically, this is done to take advantage of the lower interest rates associated with short-term borrowings and the repayment of the bonds is fit into existing repayment schedules. These bonds, however, were issued specifically to accommodate the use of proceeds from sources other than current transmission revenues (i.e., Energy Northwest bond refinancing proceeds) to make amortization payments in addition to the repayment schedule established in this proposal. If these shorter maturities were included in the repayment study, the result would be to artificially increase the amortization schedule and, therefore, the revenue requirement. As a result, we will adjust the terms and corresponding interest rates to the full 35-year maturities so that the base schedule is not artificially increased in the Final Proposal revenue requirements.

Q. *Does that conclude your testimony?*

A. Yes.